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July 9, 2009

Susan M. Hudson, Clerk
Vermont Public Service Board
112 State St., Drawer 20
Montpelier, VT 05620-2701

Re: Implementation of Standard Offer Prices for Sustainably Priced Energy Enterprise Development (SPEED) Resources – Docket No. 7523

Dear Ms. Hudson:

Longview Infrastructure is seeking to develop commercial photo-voltaic arrays in response to the opportunity created by Act 45. Longview Infrastructure submits the following comments in response to submittals made by other parties to the subject proceeding as requested in the PSB staff memo dated June 26, 2009. We first provide general comments responding to the general tone and direction of other submittals and follow that with detailed comments to specific items from the issues list. Our comments are intended to help the Board develop a comprehensive program that meets the intent of Act 45, fosters successful acquisition of renewable electricity resources, while keeping costs to Vermont ratepayers as low as possible.

General Comments

We believe many of the comments, while correct in an absolute sense, miss how inconsequential many of the fine points will be in the total electricity costs paid by the ratepayers of Vermont. Act 45 creates a pool of 50 MW for renewable energy sources of electricity such as wind, solar, small hydro, and methane. For the majority of these types of projects, capacity factors will be quite low and overall deliveries to the system may be similar to 50 MW of gas turbine peaking units. Projects utilizing renewable technologies typically depend on tax incentives to become viable, even at the prices suggested in the Act. The tax incentives depend on a pool of investors with taxable income and the desire to invest in these types of projects. There is a limited pool of such investors, suggesting that the rate of actual project execution will not be explosive in the months from September 2009 to January 2010. Witness the virtual cessation in wind project development in the US that accompanied the economic meltdown of 08-09. Therefore, we concur with others in suggesting that the Board rely heavily on the efforts of the legislature for the initial rates accompanying Docket 7523 and leave more comprehensive analysis to Docket 7533 and following.

With regard to another major discussion point regarding wheeling, the distributed nature of the generation will minimize its real impacts on the distribution and transmission systems. Most of these projects are likely to interconnect at the distribution level. They are likely to be of a size comparable with load swings in a large industrial user associated with large pieces of equipment starting and stopping. Several of the utilities' comments imply that each project will need to address wheeling to ensure compliance with the legislative mandate that all Vermont utilities take a prorata share of the energy delivered under the SO contracts. As mentioned previously, these projects are likely to be so small and so distributed that the actual impact to the operation of the system is virtually unaffected. Wheeling costs would be a extra cost burden to the ratepayers of Vermont and a windfall (albeit small) to the utilities. Several commenters supported the idea that wheeling costs should be eliminated, while others argued that FERC requires wheeling charges to apply. If wheeling charges can't be eliminated from the program by other means, the Board should pursue a program structure that minimizes these charges for the benefit of the ratepayers. We make a more detailed suggestion following more general comments.

Except for the Vermont utilities, the nature of developers interested in projects of this type and size will be very different from IPP's active in ISO-NE and other operating regions. It is more likely that these projects will be developed by companies currently participating in net metering programs, rather than the merchant generators owning baseload and other large plants in the 500MW competitive market sector. As such, it should be expected that developers of the SO projects will have little expertise with REC sales and with issues of interconnection, wheeling and delivery. The developing companies will likely have strong experience and understanding of their respective technology and how to get their output to a delivery point, but little ability to determine REC and wheeling costs as an impact to their project economic proforma in the absence of specific guidance from the Act 45 program. We suggest that potential project developers will be better able to assess their ability to deliver a project within the terms of an SO contract if those terms prescribe a price at the delivery point net of wheeling, delivery, and administrative costs.

A Potential Program Structure

The Act implies that all the Vermont utilities are to share prorata in the generation delivered from the SO contracts (except for the ability to count its own projects entirely against its own portion). If each project is required to do this accounting and billing individually, it will create a very complex administrative burden at the utilities and create a stronger argument that wheeling charges must apply. We suggest that all SO contract generation be aggregated and processed to the utilities as a single unit. For each billing cycle, an aggregator, presumably the SPEED Facilitator, would collect generation and REC data for each SO contract. In addition, the aggregator can assign generation to each utility first from generation within its service territory reducing any wheeling charges to the extent that wheeling charges must apply. Adding the wheeling cost information to the generation cost data developed by applying each generator's contract power rates, the aggregator can then easily create a homogenized power cost and send each utility a single bill to be paid back to the aggregator. The aggregator will be in a much better position than the SO generators to get the best market price for the REC credits and to minimize and control any wheeling and administrative costs that arise from the SO program. We suggest that this single unit aggregator approach best meets the Board's mandate to minimize costs to the ratepayers of Vermont while implementing the intent of Act 45 by creating simplicity in administration and program details.

Longview Infrastructure appreciates the opportunity to submit these comments for the Board's consideration and we look forward to continued participate in this exciting proceeding.

Sincerely,

J Ronald Hosie

Comments to Specific Issues from Issues List

Reference numbers match issues list outline

1.d. It seems fair to require disclosure of generic production cost figures and proformas. However, financing structures and sources of capital are often the source of a developer's competitive edge and therefore should receive some sort of protection from public scrutiny.

2.c. We believe that for Docket 7523 at least, the Board should only alter the statutory prices if it discovers the risk of a major difference in market pricing.

2.d. A relatively small amount of capacity has been developed in this size range. Any growth will largely be as a direct result of the program.

3. At least for Docket 7523, there should be no more granularity than the statute outlines. We don't read the statute as requiring that all sizes of projects be economically successful under the SO program, only that a variety of renewable technologies with up to 50 MW of capacity provide energy to the ratepayers of Vermont. This would seem to encourage the most cost-effective projects within each resource category. Any discussion of additional granularity should be reserved for future program pricing reviews.

4.b. The SO program, at least for Docket 7523, should not differentiate between plants that can or cannot use tax credits that may be available. Again, this promotes the most cost-effective projects and minimizes ratepayer cost.

5. It is unlikely that stability studies will be required for these small projects in most locations. In addition, the interconnection and facilities studies should be relatively inexpensive due to the size of the projects. While any unknown expense is a significant risk in developing smaller projects, the project developer is typically responsible for the costs of the interconnection and stability studies and we recommend that that allocation of expenses continue. It would be extremely helpful if the utilities would agree to a flat rate cost for the required studies, perhaps $5000 per project or $5/kW.

6a. We agree with other commenters that the Board should not select any particular equity ratio to apply to these projects. If anything, the Board should use a total project return that is required to entice equity and debt to the market. Unfortunately, there is no standard answer to that question as financial market conditions are fluid and change continually. The current threshold for participation is much higher than normal due to the general reluctance of the financial community to add any risk to their portfolios. Any decision about what level of risk to accept in the project due to leverage percentages should be left to the project participants.

8. Our suggested single unit aggregator approach would seem to minimize wheeling costs while avoiding precedential risks for future proceedings.

9. The generators should be required to deliver the information required to support REC packaging, verification, and sale to the SPEED Facilitator, who is in a much better position to sell them for the benefit of the ratepayers of Vermont than dozens of tiny projects.

10. These projects are so small that they would be a nuisance to administer at the ISO level. They should be treated as load reducers, consistent with their typical interconnection at distribution voltage.

11.a. One significant advantage of the SO contract concept is that a developer can obtain a contract entitling it to an income stream and therefore prove credibility to the various vendors, engineers, and financial partners necessary to make a project happen. This allows development funds to be raised and the development to be advanced with minimal risk of loss. The requirements to obtain a contract should be carefully structured to allow developers to obtain a contract with minimal prior expenditures, while still requiring some evidence of a project that is likely to be built. It would seem reasonable to require site selection and control (via ownership, lease or option), bids from one or more equipment vendors, and an LOI with equity investors as prerequisites to obtaining a SO contract. The time that a developer has to complete the project should be limited to prevent blocks of capacity from being locked up unreasonably.

11.b. Interim rates established in this docket should be available for SO Contracts to be executed until rates are revised in a future docket. This seems to be the intent of the legislation.

11.c. Each SO contract should provide a required in-service date. If the developer fails to meet the in-service date, the contract expires. The in-service date should be set with enough float that major execution disruptions (labor strikes at equipment manufacturer, loss of ship/shipping container, damage in transit, etc.) can be accommodated to the lender's satisfaction. Based on our development research to date, most of these projects should be able to be developed within one year exclusive of regulatory proceedings, so a two year in-service expiration date would seem reasonable. The one risk that should be shared outside the in-service deadline would be associated with delays in regulatory approval or interconnection availability from the utility. In both cases, the contract can make some assumptions and the deadline can be extended day for day for delays in either of these external factors.

11.d. No. The deadline approach should adequately address the interconnection availability. However, the utilities should use a first-in, first-out process for addressing interconnection requests.

11.f We agree with prior comments that no single developer should be allowed to have more than 4.4 MW of SO contracts that are not yet in-service. As its contracted projects are placed in service, the developer would become eligible for an additional contract.

11.h If the Board believes that reservations for technologies are appropriate, we recommend that the sum of such reservations be limited to less than the full 50 MW. This allows market forces to bring the most viable projects to the portfolio.

11.j. Existing projects should not qualify for the SO rates. Clearly they were developed without the need for the support of the SO rates.

11.k/l. We agree with other comments that a minimum project size should apply to the SO program that begins above the limit of the net-metering program.

14. Under our suggestion, the generators would be responsible for reporting information to the SPEED Facilitator. The SPEED Facilitator can develop a standard form or protocol for these reporting requirements. A common generation metering specification should apply to all SO contract projects.

15. The developer should select the duration based on its view of future market conditions, equipment life, and financial terms available in the market. A flat rate approach minimizes any impact to the ratepayers from longer durations.

20. Each SO contract should be for a specific net capacity. Adding or upgrading equipment to maintain or optimize the project within that limit should be up to the developer. Any expansion of net capacity should be treated as a separate project subject to obtaining a new contract, separate metering, etc.

22. An auction process is decidedly different than a standard offer process and introduces significant risk to the developers. The Act specifies a standard offer process.

25. The costs of the SPEED Facilitator should be added to the aggregate costs of the program for generation, wheeling, REC sales, etc. and divided among the utilities. Assigning costs to the developers merely raises the SO price that is required to make the projects feasible so it ends up paid by the ratepayers. The aggregating approach eliminates any risk pricing that the developers may factor in to handle costs with which they are not familiar.

Utility Settlement and Billing

29-34 Our recommended approach addresses these issues with simplicity and low cost.

36. We agree with other comments that the end of life value/risk belongs to the developer.

40. Property taxes are an expense of the project and need to be adequately addressed in the rates.

42. Even though O&M is a much smaller percentage of the overall power price in these types of renewable projects compared to more traditional forms of generation, significant economic erosion may occur within the project over the life of the contract. However, determining the proper portion of the project cost that should escalate is a complex question for the Board and undermines the nature of a standard offer contract. Some projects will obtain a long term windfall from escalation and others will lose. A developer can address this issue within a flat rate contract if the rate is adequate by customizing debt repayment to take advantage of higher operating margins in the early years.

46. The financial structure of the project should be left to the developer. The Board should try to ascertain an overall project return that is satisfactory to encourage development. For this docket, it may be adequate to assume the legislature is close in its prices, unless there is clear evidence of gross error.